Morecambe Offshore Windfarm: Generation Assets

Examination Documents

Volume 9

The Applicant’s Response to Spirit Energy’s Deadline 4 Submission Appendix D: Impact on Decommissioning of Gas Production Facilities

Document Reference: 9.59.4

Rev 02

Document History

Doc No	MOR001-FLO-CON-ENV-NOT-0038	**Rev**	02
Alt Doc No	A-200767-S00-T-REPT-001		
Document Status	Approved for Use	**Doc Date**	08 April 2025
PINS Doc Ref	9.59.4	**APFP Ref**	n/a

Rev	Date	Doc Status	Originator	Reviewer	Approver	Modifications
01	11 March 2025	Approved for Use	Xodus	Morecambe Offshore Windfarm Ltd	Morecambe Offshore Windfarm Ltd	n/a
01	08 April 2025	Approved for Use	Xodus	Morecambe Offshore Windfarm Ltd	Morecambe Offshore Windfarm Ltd	Updated in response to Deadline 5 submissions and following technical 'shared understanding' meetings with Spirit Energy

Morecambe Offshore Wind Limited

Morecambe Offshore Windfarm

Impact on Decommissioning of Gas Production Facilities

ASSIGNMENT	**A200767-S00**
DOCUMENT	**A-200767-S00-T-REPT-001**

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REV	DATE	DESCRIPTION	ISSUED	CHECKED	APPROVED	CLIENT
A04	31/03/2025	Issued for Use	[redacted]	[redacted]	[redacted]	-
A03	21/03/2025	Issued for Use	[redacted]	[redacted]	[redacted]	-
A02	10/03/2025	Issued for Use	[redacted]	[redacted]	[redacted]	-
A01	07/03/2025	Issued for Review	[redacted]	[redacted]	[redacted]	-

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EXECUTIVE SUMMARY

This report provides a summary of impact the Morecambe Offshore Windfarm (MOWF) will have on future decommissioning of the Harbour Energy and Spirit Energy's Gas platforms and infrastructure in Morecambe Bay.

The following is concluded in this report:

- There will be some restrictions on flights to vessels or rigs adjacent to the platforms, but these flights can still be conducted safely. There is no basis to conclude that the presence of the windfarm will have an adverse impact on the safety of Spirit Energy personnel or decommissioning vessel crews during the decommissioning programme.
- Throughout the decommissioning phase there will be a continuing decrease in risk to personnel as measured by Individual Risk Per Annum (IRPA) as Major Accident Hazards (MAH) are removed and the requirement to fly to NUIs is reduced and then removed.
- The conclusions of the DNV report [9] that there will be no impact on emergency evacuation and escape from either CPC1 or any of the NUIs are applicable to people located on a platform during the decommissioning phase. In the event of an emergency when there is a jack-up rig or Heavy Lift Vessel in the field there is sea room to the North of CPC1 and the West of Calder to allow the vessel master to stand-off.
- Flights to CPC1 and NUI helidecks will still be required to maintain SECEs after Cease of Production (COP) until final Disembarkation. This is an extension of operational flights beyond COP and the conclusions in the DNV report [9] remain valid during this phase: that flights can be undertaken safely with minimal impact on maintenance and project activities.
- The most likely approach for Morecambe Bay would be a successive Cease of Production through to Lighthouse Mode at each of the NUIs, followed by COP at CPC1. As the NUIs reach Lighthouse Mode there is no longer a need to fly to them and future access would be via vessel.
- There will be ongoing reduction in SECEs during the decommissioning phase following Cease of Production, particularly when hydrocarbon free status and then well plug and abandon have been achieved, progressively reducing the SECE maintenance burden.
- After Cease of Production, production critical maintenance and flights to NUIs for production resets will no longer be required.
- Jack-up rigs, heavy lift vessels and barges will have unrestricted access from the north of CPC1 and the west of Calder providing an opportunity to under crew change and decommissioning activities with no impact from the windfarm.
- There will be no restrictions on jack-up rig and lift vessel access to DP6, DP8 and DPPA.
- Once a platform has been finally disembarked ahead of the arrival of the HLV, flights to the platform helidecks are no longer required and maintenance of the helideck as CAP437 compliant is no longer required.
- The seabed around large oil and gas complexes will frequently include significant subsea infrastructure: oil and gas import and export pipelines, subsea tieback pipelines, subsea structures and power cables; the presence of the wind turbines and interconnecting cables does not present an unusual obstacle to the development of a viable mooring spread design for a jack-up rig or HLV, if required.
- There is no basis to reason that the presence of the windfarm will have a significant impact on decommissioning costs, the cost impact figures put forward by Spirit Energy and Harbour Energy are grossly exaggerated.

- Delivery of any offshore project is subject to a number of variables that can impact on the programme that need to be addressed by project management, the possibility of deferred flights due to the presence of the windfarm is another minor factor to be managed.

1 INTRODUCTION

1.1 Overview

Figure 1.1 shows the proposed unconstrained area for wind turbine placement in relationship to the Spirit and Harbour gas platforms. From the perspective of decommissioning the Development Consent Order secures the following buffer zones in the Protective Provisions in favour of both Harbour Energy (Harbour) and Spirit Energy Production UK Limited (Spirit Energy) (visually demonstrated on the below Schedule 3 Spirit Energy and Harbour Protective Provisions Plan – Revision 1 (REP2-007):

- There is a 1.5 nm marine buffer around CPC1
- There is a 500m buffer either side of existing pipelines and cables, (including the decommissioned pipeline to the removed DP3 platform)
- There is a 1nm marine buffer around Calder
- There is a 1nm marine corridor between CPC1 and Calder

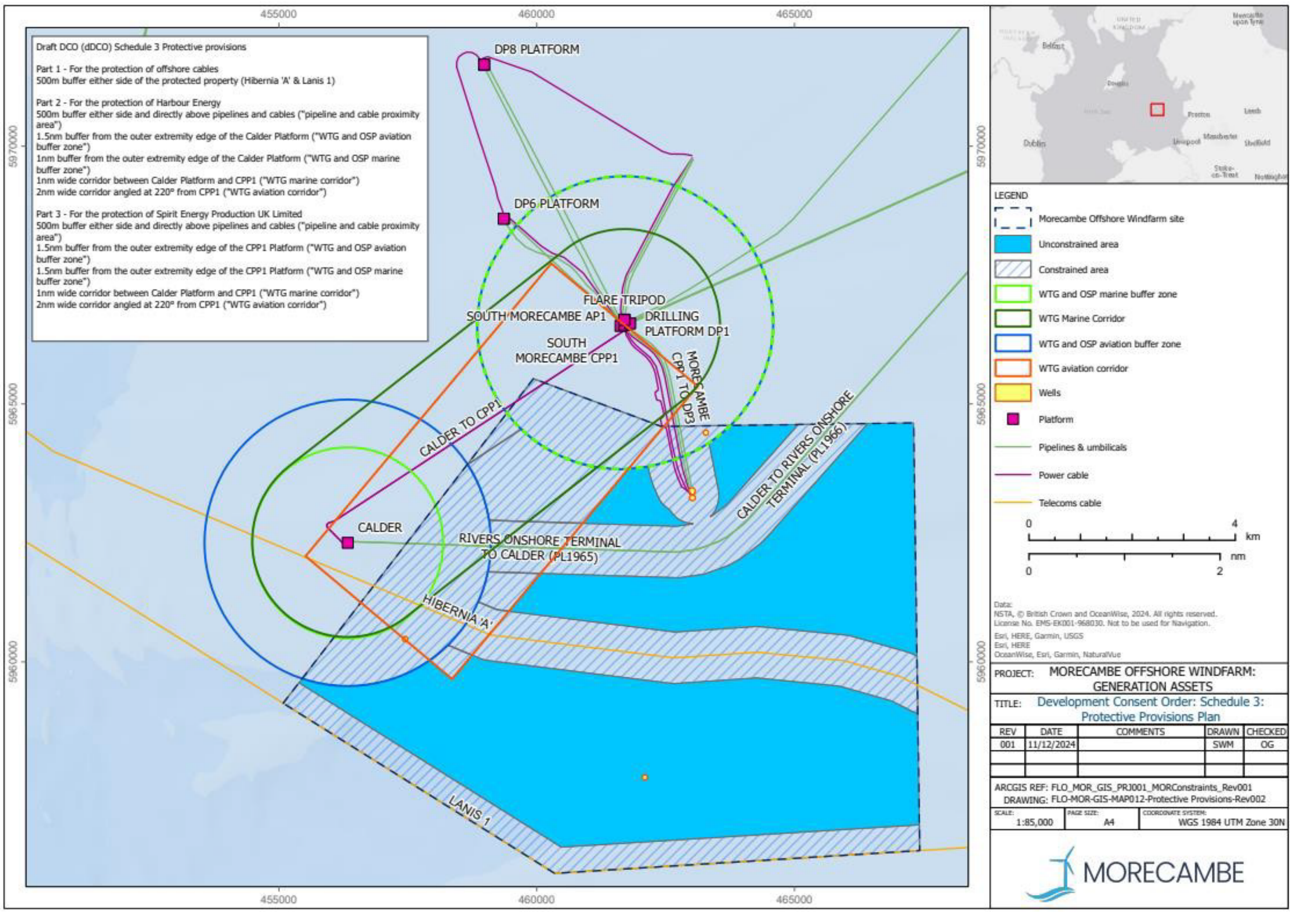


Figure 1.1 - MOWF Unconstrained Area

1.2 Scope and Objectives

This report provides a summary of impact the Morecambe Offshore Windfarm (MOWF) will have on future decommissioning of the Spirit Energy's and Harbour's gas platforms and infrastructure in Morecambe Bay.

The report will set out:

- The assets to be decommissioned
- The probable decommissioning sequence
- The potential impact of the MOWF on the decommissioning activities and programme
- A Level 5 estimate of the decommissioning costs associated with the in scope assets
- A response to specific points raised by Spirt Energy and Harbour

Detailed decommissioning programmes and schedules are not available for these assets; however, a formal Decommissioning Programme has been submitted for Calder [1], this is currently undergoing statutory consultation. The information used in this report is based upon publicly available information, it is accepted that some details may need to be updated if furthermore detailed information is provided by Spirit Energy or Harbour.

1.3 XODUS Decommissioning Experience

Xodus have extensive decommissioning experience in the UK and globally:

- By 2024 Xodus had supported 60% of UK decommissioning programmes
- During 2021- 2024 over 60-70% of approved decommissioning programmes were supported or developed by Xodus
- Xodus have completed over 420 decommissioning scopes across the full spectrum of Oil & Gas assets in late life and decommissioning operations
- Xodus provide Third Party regulatory review services to Scottish government for decommissioning methodologies and associated cost estimate for all windfarm projects in Scottish waters.

[redacted] is a passionate and knowledgeable Decommissioning Specialist striving for safe, cost and carbon efficient decommissioning. An extensive career to date, both in operator and contractor environment, of upstream commercial, technical and management experience (20+ years' experience). Focussed on driving optimisations in late life assets to deliver their maximum potential through risk management, facilitating industry collaboration and planning. Expertise in cost estimation, end of field life planning and risk management. Current attention on supporting energy transition by decarbonising assets through late life and beyond, leading decommissioning cost estimate and due diligence work for Xodus.

[redacted] is a Chartered Engineer and TUV Certified Functional Safety Engineer with over 35 years' experience working within Major Accident Hazard industries onshore and offshore: offshore oil & gas, gas reception facilities, pipelines, refineries, chemical and pharmaceutical manufacture, and energy transition (hydrogen & CO_2). This experience has been gained in site operational roles, project management, construction management, major engineering project delivery and consultancy. This experienced has contributed to a very broad multidiscipline engineering knowledge and experience. Has considerable experience in the development of Safety Management Systems, Seveso III Safety Reports, Offshore Safety Cases, Standard Operating Procedures and undertaking Process Safety / Safety Management System audits and due diligence. Extensive knowledge of process safety, process design, risk analysis, human factors, engineering management, project management, construction, decommissioning and operations management. Contributed to industry documents, including the current Oil & Gas UK Fire and Explosion Hazard Management guidance. Author of Xodus' TSR Considerations for Energy Transition Guidance. Teaching fellow on MSc courses at Aberdeen University, covering Safety Management Systems, Accident Analysis, HAZOP Application and Energy Transition Safety Considerations. Considerable experience of chairing formal hazard reviews: HAZID, ENVID, HAZOP, LOPA, Constructability Reviews and Human Factors workshops. Experience has covered a wide range of regulatory regimes, including the UK, Sweden, Netherlands, Romania, Nigeria, Trinidad, Qatar, Caspian Sea, Morocco, and Australia.

[redacted] is the Decommissioning Division Manager at Xodus with over ten years' experience of managing and executing offshore decommissioning scopes within the UKCS. He has over 20 years of experience in working in regulatory, advisory and consultancy role having spent time working for both the Scottish Government and Energy Consultancies and has developed strong working relationships with industry bodies, key stakeholders, and regulators. In his role as Decommissioning Manager, he has supported over 40 decommissioning programmes in the sector. This has included Decommissioning Programme, Environmental Appraisal, Comparative Assessments, and support studies for a number of Offshore Oil and Gas clients including ConocoPhillips, Harbour Energy, Chrysaor, ONE-Dyas, Equinor, Shell, BP, Dana, MEDCO, CNRI, Perenco, EnQuest, Fairfield, TotalEnergies, Spirit Energy, TAQA, Repsol, Neo, Neptune, Centrica Storage Ltd and Verus. He has also supported international regulators and energy companies on a range of projects including survey design, Strategic Environmental Assessment (Israel Territorial waters), Development of decommissioning guidelines and provided training courses on decommissioning and ENVID use (Japan). [redacted] is also on the board of Directors for Decommissioning Mission, the UK's decommissioning Industry body and also has a seat on the OEUK Decommissioning Steering Committee.

1.4 Abbreviations

ALARP	As Low As Reasonably Practicable
AP	Accommodation Platform
CCUS	Carbon Capture Underground Storage
COP	Cease of Production
CPC	Central Processing Complex
CPP	Central Production Platform
CSV	Construction Support Vessel
DFPVI	Drained, Flushed, Purged, Vented and Isolated
DP	Drilling Platform
DSV	Diving Support Vessel
ESD	Emergency Shut Down
HLV	Heavy Lift Vessel
IRPA	Individual Risk Per Annum

IS	Irish Sea
IVB	Independent Verification Body
MAH	Major Accident Hazard
MMS	Maintenance Management System
MOWF	Morecambe Offshore Windfarm
MNZ	Morecambe Net Zero
NUI	Normally Unattended Installation
NSTA	North Sea Transition Authority
OEUK	Offshore Energies United Kingdom
OPEX	Operational Expenditure
OPRED	Offshore Petroleum Regulator for Environment and Decommissioning
P&A	Plug and Abandon
POB	Persons on Board
ROV	Remotely Operated Vehicle
QRA	Quantitative Risk Assessment
SECE	Safety & Environmental Critical Element
SIMOPS	Simultaneous Operations
SNS	Southern North Sea
UK	United Kingdom
UKCS	United Kingdom Continental Shelf
W2W	Walk to Work

2 ASSETS TO BE DECOMMISSIONED

2.1 Overview

The following main assets will need to be decommissioned at some point by Spirt Energy or Harbour:

- The South Morecambe CPC 1 complex
- DP 6 NUI Platform
- DP 8 NUI Platform
- DPPA NUI Platform
- Calder Platform (Harbour)
- The following pipelines:
  - 36" PL144 from CPP1 to the Barrow Gas Terminal
  - 24" PL1965 from Calder to the Rivers Gas Terminal (Harbour)
  - 3" PL1966 piggybacked onto PL1965
  - 24" PL571 from DP6 to CPP1
  - 2" PL682 piggybacked onto PL571
  - 24" PL572 from DP8 to CPP1
  - 2" PL683 piggybacked onto PL572
- Power and communication cables
  - Electrical and fibre optic cable from CPP1 to Calder
  - Electrical and fibre optic cables from CPP1 to DP6 and DP8

2.2 CPC1

The Central Processing Complex (CPC1) consists of the following:

- AP1 - Accommodation Platform
- CPP1 - Central Processing Platform
- DP1 - Drilling Platform
- Tripod Flare Tower Jacket
- Inter-connecting bridges

Production wells are located on DP1, gas processing and export is located on CPP1 and AP1 provides accommodation; there are two helidecks within the Central Processing Complex, one at AP1 and one at DP1.

There are gas import pipelines from DP6 and DP8; and gas is exported through a 36" pipeline to the Barrow Gas Terminal.

2.3 Calder

Calder is an unmanned wellhead platform located over the Calder reservoir to the south-west of CPC1; the platform includes a helideck, and gas is exported via a 24" pipeline to Rivers Gas Terminal. Power is supplied to Calder by an electrical cable from CPC1. The Calder field and platform are owned by Harbour, but operated by Spirit Energy who are the duty holder.

The Calder decommissioning programme [1] states that:

"Although PL1965 has been identified by NSTA as a candidate for CCUS, there is an implicit assumption that options for re-use of the pipelines will have been exhausted before facilities and infrastructure move into the decommissioning phase and comparative assessment. Therefore, the re-use option has been excluded from the comparative assessment."

2.4 DP6

DP6 is a normally unmanned wellhead platform located over the South Morecambe reservoir to the north of CPC1; the platform includes a helideck, and gas is exported via a 24" pipeline to CPP1. Power is supplied to DP6 by an electrical cable from CPC1.

2.5 DP8

DP8 is a normally unmanned wellhead platform located over the South Morecambe reservoir to the north of CPC1; the platform includes a helideck, and gas is exported via a 24" pipeline to CPP1. Power is supplied to DP8 by an electrical cable from CPC1 via DP6.

2.6 DPPA

DPPA is a normally unmanned platform with a helideck which acts as the main gathering hub for the North Morecambe area and is located 8nm to the North of the proposed windfarm boundary limit. DPPA includes 10 development wells and a 12" pipeline to the Barrow Gas Terminals.

2.7 DP3 / DP4 (Decommissioned)

These platforms have been decommissioned, with the final lift being undertaken by the Allseas Pioneering Spirit. It should be noted that the pipelines from DP3 and 4 to CPC1 were lift in situ; the DP3 /4 Decommissioning Programme [2] states:

- PL194 (DP4 to CPP1) and PL195 (DP3 to CPP1) will be flushed and left buried in situ
- PL204 (DP4 to CPP1) and PL205 (DP3 to CPP1) will be flushed and left buried in situ
- Two redundant power cables IF-07E13 & IF-07E31 will be left buried in situ
- The power and fibre-optic cable PL2718 will be left buried in situ
- The redundant power cable IF-07E41 will be left buried in situ
- The power and fibre-optic cable IF-07E84 will be left buried in situ

Figure 2.1 shows the general layout of the South Morecambe field and the interconnecting pipelines and cables prior to the decommissioning of DP3 and DP4.

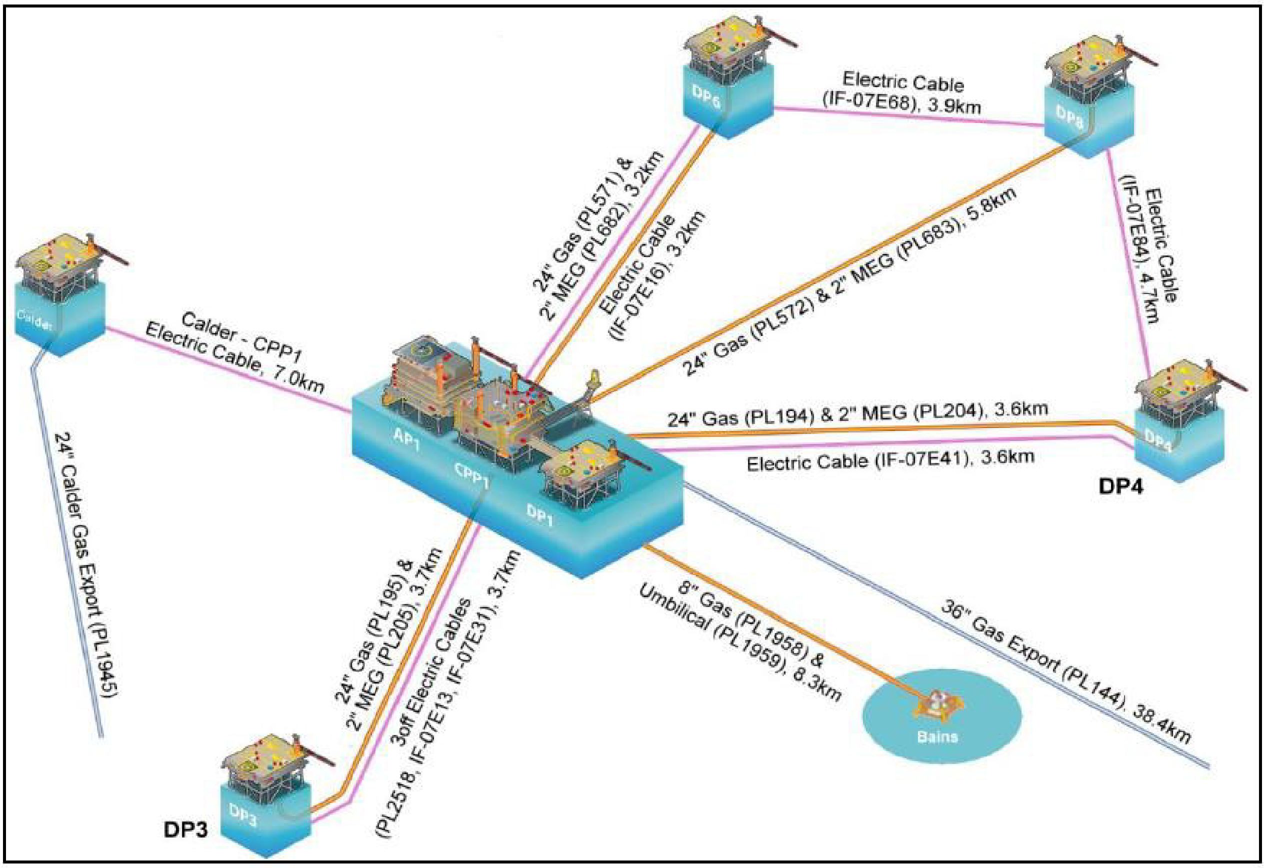


Figure 2.1 - South Morecambe Field and adjacent facilities Prior to Decommissioning of DP3 and DP4 [2]

3 DECOMMISSIONING SEQUENCE

The following sections set out a typical decommissioning sequence for facilities of this type, details specific to the decommissioning of South Morecambe and North Morecambe are covered in Section 6.

3.1 Typical Decommissioning Sequence

Typically, the decommissioning programme will go through a number of phases:

- Announcement of Cease of Production date
- Permanent Cease of Production (COP)
- Drain, Flush, Purge, Vent, and Isolate (DFPVI) / Pipeline Flushing
- Process Systems Hydrocarbon (HC) Free
- Well Plug and Abandon (P&A)
- Cold suspension
- Disembarkation
- Lighthouse mode
- Topsides / jacket removals
  - Preparation for removal
  - Removal of interconnecting bridges
  - Removal of Topsides
  - Removal of Jackets
  - Onshore Disposal and Recycling
  - Site Remediation
- Ongoing Monitoring
- Submission of Close Out Report to OPRED

For a typical decommissioning sequence for a large complex and a NUI; there are a few points to note:

- Following the announcement of the Cease of Production date some maintenance activities can be tapered as the asset is inspected and maintained to the fixed end date
- COP is the date at which the platform or platforms permanently stop producing hydrocarbons, and the exact date is influenced by a range of technical, financial, regulatory, and environmental considerations [3]. Since 1st November 2022 there is no longer requirement to complete and submit a COP report to the NSTA
- On a large complex, activities such as well P&A, cleaning and pipeline disconnect often overlap
- For a NUI there can be a delay between cleaning and pipeline disconnect and the well P&A campaign
- It is usually planned to disembark well in advance of the heavy lift activities, this reduces schedule risk to lift campaigns from minor delays in pre-disembarkation work

3.2 Decommissioning Phases

3.2.1 Post COP

Gas production has permanently ceased, and ideally if planned in advance, wells are isolated at the wellhead christmas trees, and additionally temporary plugs may be set in the wells.

There are residual hydrocarbons in topsides processing equipment until cleaned and there is still a connection to the reservoir until well P&A is complete. As a result, there is an ongoing requirement to maintain Safety & Environmental Critical Elements (SECE). Draining, Flushing, Purging, Venting and Isolation (DFPVI) of systems is simpler for a gas production platform than for an oil production platform. Further details on SECE management is provided in Section 4.2.

There is a very strong driver for the operator to minimise the time between COP and Disembarkation as there is ongoing Operational Expenditure (OPEX) incurred with no financial income from gas production, and continued asset degradation could pose a risk to onboarding personnel during preparations for removal.

3.2.2 Well Plug and Abandon

Wells need to be permanently plugged and abandon in line with regulatory requirements and recognised good practice. This requires well entry by a P&A specialist utilising a jack up rig to set permanent concrete barriers at appropriate depths based upon the reservoir characteristic. The Morecambe Bay field has a number of slant wells drilled at an angle, these require a specific well P&A rig which was constructed by Spirit Energy for DP3 and DP4 decommissioning.

Once all wells are abandoned in line with regulatory requirements and recognised good practice, they are no longer considered a source of Major Accident Hazard. Generally, this is the first point at which there can be large reduction in SECEs and SECE maintenance, although some life support SECEs remain until final disembarkation.

3.2.3 Cold Suspension

Cold suspension is a term used when all production hydrocarbon hazards have been removed [4]:

- All wells permanently Plugged and Abandoned
- All import and export pipelines have been air-gapped and physically disconnected
- Topsides process pipework has been air-gapped and physically disconnected and cleaned of any hydrocarbons

3.2.4 Disembarkation and Lighthouse Mode

The final operational and project crews are taken off the asset and the platform is permanently disembarked and enters Lighthouse Mode. The platform is left in a stable condition with Navigational Aids and in a state ready for future removal by a Heavy Lift Vessel (HLV) as agreed with the HLV contractor; the following should be noted:

- The operator can decide that the helideck is no required longer; as drone surveys are possible and this removes the requirement to maintain the helideck as compliant with CAP 437 [5], with considerable maintenance and cost savings and reduced personnel risk
- If the operator decides to keep the helideck available the most frequent flights to the platform are likely to be for helideck maintenance, flights might be quarterly
- If the helideck is not CAP 437 complaint flights to the platform are no longer possible
- Then, any access necessary, for example by HLV crew prior to the lifting operations, will need to be on a Walk to Work (W2W) basis or by rope access

The platform is left unattended until the Heavy Lift Vessel (HLV) arrives.

3.2.5 Platform Topsides and Jacket Removal

The platform topsides and jackets are removed by a contracted lift vessel for transport to an onshore disposal facility. For a complex facility this may be a series of sequential lifts as developed by the HLV contractor, for a NUI this would be a single lift of the topsides and then the jacket.

Following removal, any localised debris would be removed, and the decommissioning removal scope validated by an appropriately sized support vessel (CSV or DSV).

3.3 Post Removal

3.3.1 OPRED Close Out Report Acceptance

At the conclusion of decommissioning operations, the operator will be required to satisfy OPRED that the approved programme has been fully implemented [13]. This will involve the submission of a close out report within one year of the completion of offshore work, including debris clearance and post-decommissioning surveys.

The report will need to include:

- Information on the outcome of the decommissioning programme as a whole
- An explanation of any major variances from the programme
- The results of seabed surveys
- Demonstration of any debris clearance and monitoring undertaken
- A copy of a seabed clearance certificate (usually provided by a fishermen's' organisation)
- Details of over trawl surveys
- The results of the post-decommissioning environmental sampling survey
- Demonstration of complaint waste disposal, dismantling yard rationalisation against the submitted material inventory
- Response to any specific Decommissioning Programme requirements

The operator has a year to submit the report. On receipt of the Close-out Report OPRED will review the document and will circulate it to the stakeholders that were consulted about the Decommissioning Programme. Any points for further clarification may be put to the operator and further monitoring requirements may be stipulated.

When OPRED has concluded that it is satisfied with the Close-Out report it will write to the operator to confirm acceptance.

To complete the process the operator is reliant on external bodies, contracted vessels, the dismantling yard, and specialist services, etc. As a result of this and the overall the requirements of the above process, the time scale between removal of all structures above the sea surface and final acceptance of the Close-Out report by OPRED is uncertain and will be many years.

Setting the decommissioning date as the point at which OPRED confirms acceptance of the close-out report, is unnecessarily conservative.

3.3.2 Ongoing Monitoring

Any legacy wells within the windfarm will have been fully plugged and abandoned in line with regulatory requirements and recognised best practice but these will require ongoing monitoring. In the unlikely event that the requirement for remedial work is identified during the monitoring period, due to the presence of the wind farm any pressure relief works would require drilling from an offset distance.

For the monitoring of any pipelines left in-situ, see Section 6.5.

3.4 Production Extension

Through discussion with regulator, it is possible to extend production beyond the dates set out in a submitted Decommissioning Programme; however, this comes with some potential implications:

- The basis for the Environmental Impact Assessment (EIA) supporting the Decommissioning Programme may have changed requiring an update of the EIA
- Any extension of production significantly beyond the declared Cease of Production may require a substantial Life Extension project to ensure continued safe and efficient production
- Any extension of production would need to be justified in the context of The Oil and Gas Authority Strategy [6] which obliges operators to assist the Secretary of State with meeting the net zero target

4 SAFETY CASE AND SECE MANAGEMENT

4.1 Safety Case Updates

It is a requirement of the Offshore Installations Safety Case Regulations [8] that the Duty Holder maintains a Safety Case that accurately reflects the status of the installation; that the Duty Holder must revise a current Safety Case when appropriate, and that the Duty Holder prepares a Dismantling Safety Case at the appropriate stage. During the decommissioning phase there will be a number of Material Changes to update the Safety Case as the MAH profile and the associated SECEs change as required by Regulation 24 (1) [8]. It is typical for a complex such as CPC1 that updates will be required at the following stages in the decommissioning programme:

- Cease of Production
- CPP1 Hydrocarbon free
- Wells Plugged and Abandoned
- Lighthouse Mode
- Dismantling Safety Case

As the programme is much shorter for a NUI there are likely to be fewer Safety Case updates, typically:

- Cease of Production
- Hydrocarbon free (Wells Plugged and Abandoned and pipeline physically disconnected)
- Lighthouse Mode
- Dismantling Safety Case

Subject to the agreement of the HSE, it is possible to produce a single Safety Case after COP covering all of the above phases, particularly for a NUI. It would be normal practice to retire the asset Quantitative Risk Assessment (QRA) as reported in the Safety Case once the asset is hydrocarbon free.

4.2 SECE Management

4.2.1 Overview

There are incentives for the Operator to manage down the SECE requirements as MAHs are removed from the asset. Progressively removing the requirement to maintain SECEs has the following advantages:

- Reduces maintenance costs
- Allows for resource to be focussed on maintaining the remaining SECEs
- Enables the reduction of any backlog on remaining SECEs
- Frees up platform beds / flights for decommissioning project personnel; and
- For a NUI reduces maintenance personal IRPA as there will be fewer flights to the NUI

Information has not been provided on Spirit's classification of SECEs; however, there is a large degree of standardisation across the industry, so the following sections are based on a typical SECE breakdown for assets of this nature. The following sections can only be indicative; as the removal of SECEs needs to be a risk-based approach developed by the operator and accepted by the Competent Authority through a Safety Case Material Change.

Any remaining declared SECEs need to be maintained in line with the SECE Performance Standard and are subject to verification by the appointed Independent Verification Body (IVB).

4.2.2 Calder and Other NUIs

Cease of Production

The platform topsides process systems are isolated from hydrocarbon sources as the valves on the wellhead christmas trees and the Riser Emergency Shutdown Valves are locked closed; however, the potential for leakage past these valves remains.

Following Cease of Production there will be a reduction in requirements for maintenance personnel to fly to a NUI:

- The following SECEs can likely be retired:
  - Pipework hydrocarbon containment, integrity, and corrosion management, etc.
  - Emergency Shutdown systems (as these systems act on valves that are permanently closed)
  - Blowdown systems
- There is no longer a requirement for flights for:
  - Production resets
  - Production critical maintenance

Hydrocarbon Free

For a NUI this can be achieved 3-6 months after COP; however, the actual date is subject to the operator's priorities and decommissioning project schedule targets. At this point all process systems have been Drained, Flushed, Purged, Vented, and Isolated (DFPVI), wells have been Plugged & Abandoned, the export pipeline is flushed and physically disconnected, when this is achieved:

- The only remaining SECEs to maintain will likely be:
  - Structural integrity
  - Helideck
  - Platform crane
  - Lifesaving (escape, evacuation equipment, emergency lighting, etc.)
  - Navigational aids

Lighthouse Mode

The asset has been disembarked for the final time and is ready for removal by the HLV. It is likely the operator will not want to maintain the helideck as this removes a maintenance burden and remove risk associated with flights to maintain the helideck.

The only remaining SECEs to maintain will likely be:

- Structural integrity (this can be inspected remotely via drone)
- Navigational aids (batteries / solar panel will be provided to maintain power to these for as long as required)

4.2.3 CPC1

Cease of Production

The platform topsides process systems are isolated from hydrocarbon sources as the valves on the wellheads christmas trees at DP1 are locked closed and the Riser Emergency Shutdown Valves on CPP1 are locked closed; however, the potential for leakage past these valves remains.

As there are numerous sources of hydrocarbons remaining there is not likely to be a significant reduction in SECE maintenance until CPP1 is hydrocarbon free but there is no longer a requirement for production critical maintenance to be undertaken.

CPP1 Hydrocarbon Free

For CPC1 this can likely be achieved 3-6 months after COP. At this point all process systems have been Drained, Flushed, Purged, Vented, and Isolated (DFVPI), the import/export pipelines are flushed and physically disconnected, and there is no longer a produced hydrocarbon risk on CPP1.

When this is achieved the following SECEs can likely be retired, or have their scope reduced:

- Pipework hydrocarbon containment, integrity, and corrosion management, etc.
- Emergency Shutdown systems (as these systems act on valves that are permanently closed)
- Blowdown systems
- CPP1 Fire & Gas detection systems
- CPP1 deluge systems
- CPP1 Passive Fire Protection
- Process pressure vessel inspections
- Process pressure relief devices

Wells P&A

Following well P&A on DP1 there will be an opportunity to further retire SECEs on DP1, including:

- Fire & Gas detection systems
- Deluge systems
- Well integrity

Lighthouse Mode

The asset has been disembarked for the final time and is ready for removal by the HLV. It is likely the operator will not want to maintain the helideck as this removes a maintenance burden and remove risk associated with flights to maintain the helideck.

The only remaining SECEs to maintain will likely be:

- Structural integrity (this can be inspected remotely via drone)
- Navigational aids (batteries / solar panel will be provided to maintain power to these for as long as required)

4.2.4 Overall SECE Reduction Impact

As the NUIs (Calder / DP6 / DP 8 and DPPA) reach Cease of Production, achieve hydrocarbon free status, and finally enter Lighthouse Mode; there will be an ongoing progressive reduction in production critical and SECE maintenance requirements, freeing up capacity to address any backlog and to maintain remaining SECEs across the field.

4.3 Impact of Decommissioning on Platform Access Requirements

Table 4-1 to Table 4-3 below outline the changes in access requirements as the assets progress through the decommissioning programme for Calder, the other NUIS and CPC1. The SECE categories used are based on an industry standard approach; actual SECE categorisation is determined by Spirit Energy, the retirement of SECEs is subject to risk assessment by the operator and the actual status of the platform, so the below can only be indicative. When a SECE is retired maintenance is no longer required and the activities can be removed from the Maintenance Management System (MMS).

Figure 5.1 and Figure 5.2 show indictive schedules for decommissioning of a complex and a NUI respectively, the red line indicates how the maintenance and corresponding access requirements reduce over the decommissioning programme.

Table 4-1: Calder - Changes in Access Requirements Through Decommissioning Phases

PHASE / STAGE	DEFINITION	DURATION	MAINTENANCE REQUIREMENTS	ACCESS OPTIONS	ACCESS FREQUENCY	RISK TO PERSONNEL	COMMENTS
COP Date Announced	Formal announcement of COP date	The delay between the announcement and the final COP can vary widely and is at the Operator's discretion driven largely by economics	Maintenance activities due beyond the COP date will not be required. This has no impact on scheduled work.	Helicopter via CPC1	No change	No change	The Licensee is not required to complete and submit a COP report to the NSTA The date can be subject to change at the Licensee's discretion
COP	Production has permanently stopped with no intention to restart	Milestone	Production critical maintenance stops Production resets not required No reduction in SECE Maintenance	Helicopter via CPC1	Reduced	Reduction in IRPA related to reduced flights	Production will not restart after COP Post COP facility running costs remain, so there is a financial incentive for the Operator to get to final disembarkation as soon as possible

PHASE / STAGE	DEFINITION	DURATION	MAINTENANCE REQUIREMENTS	ACCESS OPTIONS	ACCESS FREQUENCY	RISK TO PERSONNEL	COMMENTS
DFPVI / Pipeline Flushing	DFPVI all topsides system Isolate topsides from wellhead christmas trees and export pipeline	2 months	As above	Helicopter via CPC1 DFPVI project team could fly direct to Calder but there is no advantage	Driven by workscope and project schedule Maintenance access continues as above	More frequent flights for project work crew, IRPA for work crew is probably increased	DFPVI crew will be on platform regularly and will be accommodated on CPC1 Delays in DFPVI are manageable and will not impact Well P&A and HLV schedules
Process Systems Hydrocarbon Free	Topsides process systems are free of production hydrocarbons	Milestone	The following SECEs can be retired: • ESD, Blowdown • Relief valves • Hydrocarbon containment • Hazardous drains	Helicopter via CPC1	Further reduced associated with SECE retirement	Further reduction in IRPA related to reduced flights	The wells remain a source of potential MAH
Pipeline Disconnected	Export pipeline has been flushed from the platform and is physically isolated	Milestone	The following SECEs can be retired: • Pipelines and risers • Cranes	Helicopter via CPC1	Small reduction associated with SECE retirement	Small reduction in IRPA related to reduced flights	Regarding cranes, future lifts from supply vessels and onto the NUI for Well P&A can be undertaken using the jack-up cranes
Pre Well P&A ("Warm Stack")	Wells are isolated at the christmas trees, there are no other sources of hydrocarbon on the platform	The duration is likely determined by the Jack-Up contract date	Reduced maintenance as production critical maintenance work has stopped and the above SECEs have been retired	Helicopter via CPC1	Flights to platform will be significantly reduced from operational phase	Significant reduction in IRPA from operational phase	There will likely be a programmed delay between completion of preparation for P&A and the arrival of the well P&A jack-up

PHASE / STAGE	DEFINITION	DURATION	MAINTENANCE REQUIREMENTS	ACCESS OPTIONS	ACCESS FREQUENCY	RISK TO PERSONNEL	COMMENTS
Well P&A	Well intervention by specialists using equipment delivered by supply vessel. At least 2 permanent concrete plugs are set in the well	3-4 months	Operational crew access is still required as above	Helicopter via CPC1 Helicopter direct to jack-up	Only well P&A crew change	Jack-up crew risks are outside the scope of this assessment	Undertaken by a specialist, jack-up rig located alongside the NUI There is no requirement to shuttle jack-up crew via CPC1 Flights to the jack-up face the same restriction as to the Calder helideck P&A crew will be accommodated on the jack-up so work can continue if a flight is deferred P&A may be longer than for standard wells as a result of unusual slant wells drilled at an angle
Wells Plugged and Abandoned	Wells are permanently plugged and abandon in line with regulatory requirements	Milestone	The following SECEs can be retired: • F&G Detection • Ignition prevention • Fire pump and deluge • Helideck • Well control	Helicopter via CPC1	Significantly reduced from operational phase	IRPA is reduced as there are fewer flights to the platform	Post Well P&A all sources of hydrocarbon MAH are removed from the platform The remaining SECEs are: • Structural Integrity • 'Lifesaving' escape and evacuation etc. • Navaids, Collision Avoidance
Cold Suspension	The platform is free of all production HC hazards	1 month	Remaining SECEs are: • Structural Integrity • 'Lifesaving' escape and evacuation etc. • Navaids, Collision Avoidance	Helicopter via CPC1	Minimal requirement	IRPA is reduced as there are fewer flights to the platform	There may be an infrequent requirement to fly to the NUI for any final work in preparation for disembarkation

PHASE / STAGE	DEFINITION	DURATION	MAINTENANCE REQUIREMENTS	ACCESS OPTIONS	ACCESS FREQUENCY	RISK TO PERSONNEL	COMMENTS
Final Disembarkation	Personnel leave the platform for the final time with no planned return	Milestone	N/A	N/A	N/A	N/A	After disembarkation the helideck is no longer required
Lighthouse Mode	The asset has been disembarked for the final time and is ready for removal by the HLV.	Indeterminate - can be an extended period dependant on HLV contracting strategy	Structural integrity and Navaids need to be maintained Navaids can be solar powered with battery back up	Inspection can be carried out remotely using drones (this removes risk to personnel) W2W vessel or rope access	Very infrequent if required at all	Risks to personnel from accessing the NUI are completely removed	The remaining SECEs are: • Structural Integrity • Navaids, Collision Avoidance Ongoing costs are minimal There will be a programmed delay between disembarkation and removal to minimise any financial risk to the HLV campaign
Removal	The Topside and Jacket are removed by a contracted HLV	1 month	N/A	Helicopter direct to the HLV	HLV crew change	HLV crew risks are outside the scope of this assessment	Crew change flights can be made to the HLV in the stand-off position with no impact from the windfarm HLV can approach from the west with no impact from the windfarm
Subsea Disconnection	Address subsea infrastructure to remove stabilisations and perform remediation	Dependent on scope	N/A	Access is not required; these activities are all undertaken via service vessel	N/A	Subsea vessel crew risks are outside the scope of this assessment	All undertaken via service vessel

PHASE / STAGE	DEFINITION	DURATION	MAINTENANCE REQUIREMENTS	ACCESS OPTIONS	ACCESS FREQUENCY	RISK TO PERSONNEL	COMMENTS
Decommiss-ioning Complete	All activities in the Decommissioning Programme have been completed and accepted as such by OPRED	Indeterminate - OPRED will need time to review and accept the report and they may require clarifications	N/A	N/A	N/A	N/A	This is an acceptance of the report which will only be submitted when the licensee is confident that all work in the DP is complete

Table 4-2: NUIs DP6 / DP8 / DPPA - Changes in Access Requirements Through Decommissioning Phases

PHASE / STAGE	DEFINITION	DURATION	MAINTENANCE REQUIREMENTS	ACCESS OPTIONS	ACCESS FREQUENCY	RISK TO PERSONNEL	COMMENTS
COP Date Announced	Formal announcement of COP date	The delay between the announcement and the final COP can vary widely and is at the Operator's discretion driven largely by economics	Maintenance activities due beyond the COP date will be removed from the MMS. This has no impact on scheduled work.	Helicopter via CPC1	No change	No change	The Licensee is not required to complete and submit a COP report to the NSTA The date can be subject to change at the Licensee's discretion
COP	Production has permanently stopped with no intention to restart	Milestone	Production critical maintenance stops Production resets not required	Helicopter via CPC1	Reduced	Reduction in IRPA related to reduced flights	Production will not restart after COP Post COP facility running costs remain, so there is a financial incentive for the Operator to get to final disembarkation as soon as possible

PHASE / STAGE	DEFINITION	DURATION	MAINTENANCE REQUIREMENTS	ACCESS OPTIONS	ACCESS FREQUENCY	RISK TO PERSONNEL	COMMENTS
			No reduction in SECE Maintenance				
DFPVI / Pipeline Flushing	DFPVI all topsides system Isolate topsides from wellhead christmas trees and export pipeline	2 months	As above	Helicopter via CPC1 DFPVI project team could fly direct to NUI	Driven by workscope and project schedule Maintenance access continues as above	More frequent flights for project work crew, IRPA for work crew is probably increased	DFPVI crew will be on platform regularly, operational support will be on CPC1 Delays in DFPVI are manageable and will not impact Well P&A and HLV schedules
Process Systems Hydrocarbon Free	Topsides process systems are free of production hydrocarbons	Milestone	The following SECEs can be retired: • ESD, Blowdown • Relief valves • Hydrocarbon containment • Hazardous drains	Helicopter via CPC1	Further reduced associated with SECE retirement	Further reduction in IRPA related to reduced flights	The wells remain a source of potential MAH
Pipeline Disconnected	Export pipeline has been flushed from the platform and is physically isolated	Milestone	The following SECEs can be retired: • Pipelines and risers • Cranes	Helicopter via CPC1	Small reduction associated with SECE retirement	Small reduction in IRPA related to reduced flights	Regarding cranes, future lifts from supply vessels and onto the NUI for Well P&A can be undertaken using the jack-up cranes
Pre Well P&A ("Warm Stack")	Wells are isolated at the christmas trees, there are	The duration is likely determined by the	Reduced maintenance as production critical maintenance work has	Helicopter via CPC1	Flights to platform will be significantly	Significant reduction in IRPA from	There will likely be a programmed delay between completion of preparation for P&A and the arrival of the well P&A jack-up

PHASE / STAGE	DEFINITION	DURATION	MAINTENANCE REQUIREMENTS	ACCESS OPTIONS	ACCESS FREQUENCY	RISK TO PERSONNEL	COMMENTS
	no other sources of hydrocarbon on the platform	Jack-Up contract date	stopped and the above SECEs have been retired		reduced from operational phase	operational phase	
Well P&A	Well intervention by specialists using equipment delivered by supply vessel. At least 2 permanent concrete plugs are set in the well	3-4 months	Operational crew access is still required as above	Helicopter via CPC1 Helicopter direct to the NUI Helicopter direct to jack-up	Only well P&A crew change	Jack-up crew risks are outside the scope of this assessment	Undertaken by a specialist, jack-up rig located alongside the NUI There is no requirement to shuttle jack-up crew via CPC1 Flights to the jack-up face the same restriction as to the Calder helideck P&A crew will be accommodated on the jack-up so work can continue if a flight is deferred P&A may be longer than for standard wells as a result of unusual slant wells drilled at an angle
Wells Plugged and Abandoned	Wells are permanently plugged and abandon in line with regulatory requirements	Milestone	The following SECEs can be retired: • F&G Detection • Ignition prevention • Fire pump and deluge • Helideck • Well control	Helicopter via CPC1 Helicopter direct to the NUI	Significantly reduced from operational phase	IRPA is reduced as there are fewer flights to the platform	Post Well P&A all sources of hydrocarbon MAH are removed from the platform The remaining SECEs are: • Structural Integrity • 'Lifesaving' escape and evacuation etc. • Navaids, Collision Avoidance
Cold Suspension	The platform is free of all	1 month	Remaining SECEs are: • Structural Integrity	Helicopter via CPC1	Minimal requirement	IRPA is reduced as there are	There may be an infrequent requirement to fly to the NUI for any final work in preparation for disembarkation

PHASE / STAGE	DEFINITION	DURATION	MAINTENANCE REQUIREMENTS	ACCESS OPTIONS	ACCESS FREQUENCY	RISK TO PERSONNEL	COMMENTS
	production HC hazards		• 'Lifesaving' escape and evacuation etc. • Navaids, Collision Avoidance			fewer flights to the platform	
Final Disembarkation	Personnel leave the platform for the final time with no planned return	Milestone	N/A	N/A	N/A	N/A	After disembarkation the helideck is no longer required
Lighthouse Mode	The asset has been disembarked for the final time and is ready for removal by the HLV.	Indeterminate - can be an extended period dependant on HLV contracting strategy	Structural integrity and Navaids need to be maintained Navaids can be solar powered with battery back up	Inspection can be carried out remotely using drones (this removes risk to personnel) W2W vessel or rope access	Very infrequent if required at all	Risks to personnel from accessing the NUI are completely removed	The remaining SECEs are: • Structural Integrity • Navaids, Collision Avoidance Ongoing costs are minimal There will be a programmed delay between disembarkation and removal to minimise any financial risk to the HLV campaign
Removal	The Topside and Jacket are removed by a contracted HLV	1 month	N/A	Helicopter direct to the HLV	HLV crew change	HLV crew risks are outside the scope of this assessment	Crew change flights can be made to the HLV in the stand-off position with no impact from the windfarm HLV can approach from the west with no impact from the windfarm
Subsea Disconnection	Address subsea infrastructure to remove	Dependent on scope	N/A	Access is not required; these activities are all	N/A	Subsea vessel crew risks are outside the	All undertaken via service vessel

PHASE / STAGE	DEFINITION	DURATION	MAINTENANCE REQUIREMENTS	ACCESS OPTIONS	ACCESS FREQUENCY	RISK TO PERSONNEL	COMMENTS
	stabilisations and perform remediation			undertaken via service vessel		scope of this assessment	
Decommiss-ioning Complete	All activities in the Decommissioning Programme have been completed and accepted as such by OPRED	Indeterminate - OPRED will need time to review and accept the report and they may require clarifications	N/A	N/A	N/A	N/A	This is an acceptance of the report which will only be submitted when the licensee is confident that all work in the DP is complete

Table 4-3: CPC1 - Changes in Access Requirements Through Decommissioning Phases

PHASE / STAGE	DEFINITION	DURATION	MAINTENANCE REQUIREMENTS	ACCESS OPTIONS	ACCESS FREQUENCY	RISK TO PERSONNEL	COMMENTS
COP Date Announced	Formal announcement of COP date	The delay between the announcement and the final COP can vary widely and is at the Operator's discretion driven largely by economics	Maintenance activities due beyond the COP date will be removed from the MMS. This has no impact on scheduled work.	Helicopter direct to CPC1	No change	No change	The Licensee is not required to complete and submit a COP report to the NSTA The date can be subject to change at the Licensee's discretion
COP	Production has permanently stopped with no intention to restart	Milestone	Production critical maintenance stops Production resets not required No reduction in SECE Maintenance	Helicopter direct to CPC1	No change	No change to flight related IRPA	Production will not restart after COP Post COP facility running costs remain, so there is a financial incentive for the Operator to get to final disembarkation as soon as possible
DFPVI / Pipeline Flushing	DFPVI all topsides system Isolate topsides from wellhead christmas trees and export pipeline	3-6 months	As above	Helicopter direct to CPC1	No change	No change to flight related IRPA	DFPVI crew will be accommodated on CPC1 Delays in DFPVI are manageable and will not impact Well P&A and HLV schedules
Process Systems	Topsides process systems are free	Milestone	The following SECEs can be retired: • ESD, Blowdown • Relief valves	Helicopter direct to CPC1	No change	No change to flight related IRPA	Hydrocarbon free on CPP1 can be achieved ahead of the completion of well P&A, at this

PHASE / STAGE	DEFINITION	DURATION	MAINTENANCE REQUIREMENTS	ACCESS OPTIONS	ACCESS FREQUENCY	RISK TO PERSONNEL	COMMENTS
Hydrocarbon Free	of production hydrocarbons		• Hydrocarbon containment • Hazardous drains				point the only source of production hydrocarbons is on the drilling platform DP1 Platform beds will likely remain fully occupied as emphasis moves from operations to down engineering to well P&A
Pipeline Disconnected	Export pipeline has been flushed from the platform and is physically isolated	Milestone	The following SECEs can be retired: • Pipelines and risers	Helicopter direct to CPC1	No change	No change to flight related IRPA	
Pre Well P&A ("Warm Stack")	Wells are isolated at the christmas trees, there are no other sources of hydrocarbon on the platform	N/A	N/A	N/A	N/A	N/A	CPC1 is unlikely to go through this phase as platform down engineering will overlap well P&A
Well P&A	Well intervention by specialists using equipment delivered by supply vessel. At least 2 permanent concrete plugs are set in the well	5-6 months	Maintenance of remaining SECEs is still needed	Helicopter direct to CPC1 Helicopter to jack-up helideck	Only well P&A crew change	Jack-up crew risks are outside the scope of this assessment	Undertaken by a specialist, jack-up rig located alongside DP1 Flights to the jack-up face the same restriction as to the CPC1 helidecks P&A crew will be accommodated on the jack-up or in platform beds so work can continue if a flight is deferred P&A may be longer than for standard wells as a result of unusual slant wells drilled at an angle

PHASE / STAGE	DEFINITION	DURATION	MAINTENANCE REQUIREMENTS	ACCESS OPTIONS	ACCESS FREQUENCY	RISK TO PERSONNEL	COMMENTS
Wells Plugged and Abandoned	Wells are permanently plugged and abandon in line with regulatory requirements	Milestone	The following SECEs can be retired: • F&G Detection • Ignition prevention • Fire pump and deluge • Helideck • Well control	Helicopter direct to CPC1	Significantly reduced from operational phase	IRPA is reduced as there are fewer flights to the platform	Post Well P&A all sources of hydrocarbon MAH are removed from the platform The remaining SECEs are: • Structural Integrity • 'Lifesaving' escape and evacuation etc. • Navaids, Collision Avoidance
Cold Suspension	The platform is free of all production HC hazards	Uncertain as determined by detailed programme schedule	Remaining SECEs are: • Structural Integrity • 'Lifesaving' escape and evacuation etc. • Navaids, Collision Avoidance	Helicopter direct to CPC1	Crew change for a much reduced POB	IRPA is reduced as there are fewer flights to the platform	There may still be a reduced crew on the platform for any final work in preparation for disembarkation
Final Disembarkation	Personnel leave the platform for the final time with no planned return	Milestone	N/A	N/A	N/A	N/A	After disembarkation the helideck is no longer required
Lighthouse Mode	The asset has been disembarked for the final time and is ready for removal by the HLV.	Indeterminate - can be an extended period dependant on HLV contracting strategy	Structural integrity and Navaids need to be maintained Navaids can be solar powered with battery back up	Inspection can be carried out remotely using drones (this removes risk to personnel)	Very infrequent if required at all	Risks to personnel from accessing CPC1 are completely removed	The remaining SECEs are: • Structural Integrity • Navaids, Collision Avoidance Ongoing costs are minimal

PHASE / STAGE	DEFINITION	DURATION	MAINTENANCE REQUIREMENTS	ACCESS OPTIONS	ACCESS FREQUENCY	RISK TO PERSONNEL	COMMENTS
				W2W vessel or rope access			There will be a programmed delay between disembarkation and removal to minimise any financial risk to the HLV campaign
Removal	The Topside and Jacket are removed by a contracted HLV	2 months	N/A	Helicopter direct to the HLV	HLV crew change	HLV crew risks are outside the scope of this assessment	Crew change flights can be made to the HLV in the stand-off position with no impact from the windfarm HLV can approach from the north with no impact from the windfarm
Subsea Disconnection	Address subsea infrastructure to remove stabilisations and perform remediation	Dependent on scope	N/A	Access is not required; these activities are all undertaken via service vessel	N/A	Subsea vessel crew risks are outside the scope of this assessment	All undertaken via service vessel
Decommiss-ioning Complete	All activities in the Decommissioning Programme have been completed and accepted as such by OPRED	Indeterminate - OPRED will need time to review and accept the report and they may require clarifications	N/A	N/A	N/A	N/A	This is an acceptance of the report which will only be submitted when the licensee is confident that all work in the DP is complete

5 DECOMMISSIONING SCHEDULE

5.1 Overview

The NUIs, Calder, DP6, DP8 and DPPA rely on the central complex CPC1 for gas export, or power, or both. As a result, it is most likely that the NUIs will be decommissioned before the hub CPC1. The most likely approach would be a successive Cease of Production through to Lighthouse Mode at the NUIs followed by COP at CPC1.As the NUIs reach Lighthouse Mode the need to fly to these assets would feasibly cease and future access could be via vessel.

Condensing the removal works into as few campaigns as possible may be financially beneficial. However, the detail is subject to economic assessment at each of the NUIs and Spirit Energy's and Harbour's plans for the field.

This section provides an overview of the likely decommissioning schedule; however, the actual programme will be subject to a number of factors, including: operator business priorities and expenditure scheduling, concurrent decommissioning activities, and availability of contracted vessels. However, it is usually in the operator's interest to minimise the decommissioning schedule as shortening the programme will often make substantial savings in facility running costs, onshore support roles and project management costs.

Figure 5.1 and Figure 5.2 show indictive schedules for decommissioning up to full removal of a complex and a NUI respectively. The red line indicates how the maintenance and corresponding access requirements reduce over the decommissioning programme. This can only be indicative as the details of Spirit Energy's maintenance routines are not available and all retirement of SECEs is subject to a detailed risk assessment. There is a corresponding reduction in IRPA associated with a reduction in flights.

Table 5-1 and Table 5-2 provide indicative decommissioning milestone dates following COP for CPC1 and Calder (and other NUIs) respectively and an assessment of the level of schedule risk to the achievement of these dates.

Table 5-1: CPC1 - Decommissioning Milestone Dates

MILESTONE	DURATION AFTER COP	SCHEDULE RISKS	RISK RANKING	COMMENTS
Cease of Production	N/A	N/A	N/A	
Process Systems HC Free	6 months	Undertaken by Operations staff	L	This is simpler for gas platforms
Well P&A Complete	8 months	Subject to: • Availability of jack-up rig or installation of modular rig for slant wells • Possible well integrity issues that need to be addressed	M	There are a comparatively small number of wells, but it's anticipated that there will be slant wells

MILESTONE	DURATION AFTER COP	SCHEDULE RISKS	RISK RANKING	COMMENTS
Cold Suspension Start	9 months	Dependent on completion of above activities	M	Asset free of all sources of production hydrocarbons
Disembarkation / Lighthouse Mode	12 months	On completion of the above activities this is a decision by the operator	M	For a complex there may be tasks to be undertaken during cold suspension in preparation of final disembarkation
Removal	2-3 years	Subject to: • Heavy lift vessel availability • HLV preferred removal window • Field removal strategy (i.e., removal of multiple assets in single campaign)	H	Will be dependent on vessel availability and contracting strategy, typically a contract will be awarded with a removal window with the actual dates at the discretion of the HLV contractor
Close Out Report Acceptance	5-6 years	Subject to completion of all of the activities There are a number of requirements outside the direct control of operator, including: • Survey • Remediation • Waste management, etc. Operator has a year to submit the report on completion of all activities and there is statutory consultation requirement	H	Close out report submitted to OPRED within a year of the completion of all decommissioning activities

Table 5-2: Calder - Decommissioning Milestone Dates

MILESTONE	DURATION AFTER COP	SCHEDULE RISKS	RISK RANKING	COMMENTS
Cease of Production	N/A	N/A	N/A	
Process Systems HC Free	4 months	Undertaken by Operations staff	L	This is simpler for gas platforms
Well P&A Complete	7 months	Subject to: • Availability of jack-up rig or installation of modular rig for slant wells • Possible well integrity issues that need to be addressed	L	There are a small number of wells, but it's anticipated that there will be slant wells
Cold Suspension Start	8 months	Dependent on completion of above activities	L	Asset free of all sources of production hydrocarbons
Disembarkation / Lighthouse Mode	8 months	On completion of the above activities this is a decision by the operator	L	
Removal	2-3 years	Subject to: • Heavy lift vessel availability • HLV preferred removal window • Field removal strategy (i.e., removal of multiple assets in single campaign)	H	Will be dependent on vessel availability and contracting strategy, typically a contract will be awarded with a removal window with the actual dates at the discretion of the HLV contractor
Close Out Report Acceptance	5-6 years	Subject to completion of all of the activities There are a number of requirements outside the direct control of operator, including: • Survey • Remediation • Waste management, etc. Operator has a year to submit the report on completion of all activities and there is statutory consultation requirement	H	Close out report submitted to OPRED within a year of the completion of all decommissioning activities

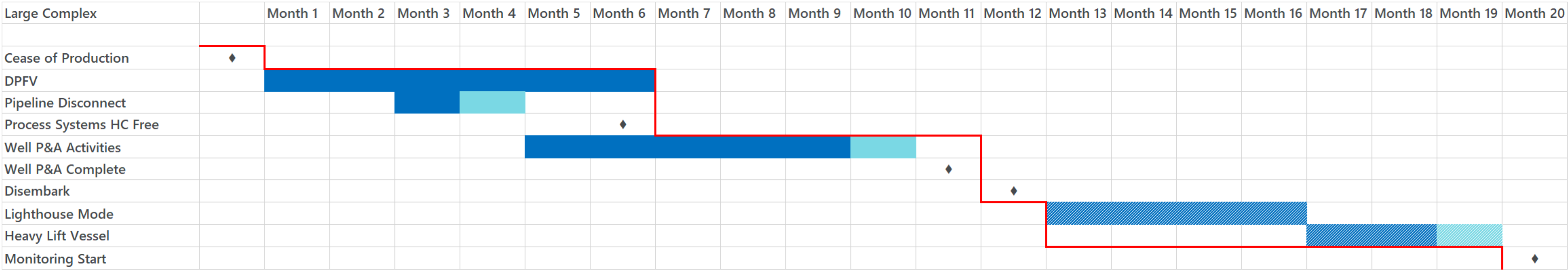


Figure 5.1 - Indicative Decommissioning Schedule for a Complex

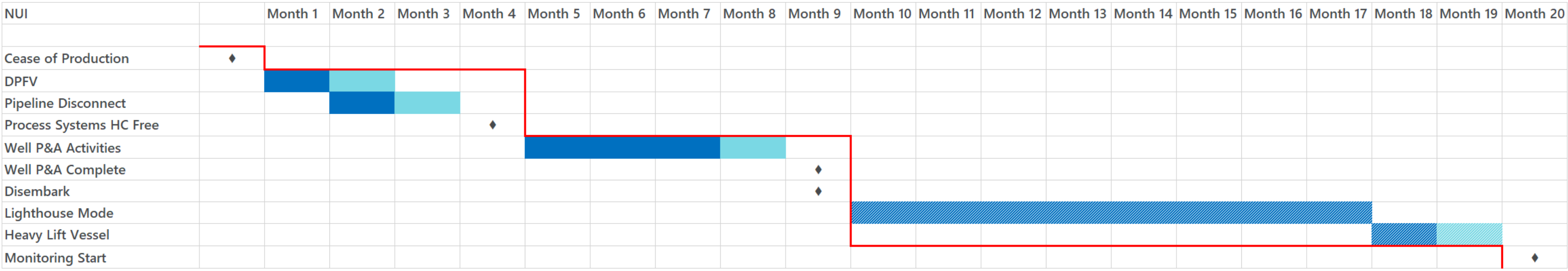
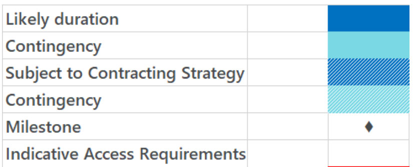


Figure 5.2 - Indicative Decommissioning Schedule for a NUI



Based on industry norms [10] The following durations could be expected for the South Morecambe decommissioning schedule

- Calder Cease of Production to Lighthouse Mode – 6 to 9 months
- CPC1 Cease of Production to Lighthouse Mode – 9 to 12 months
- Calder well P&A - 3 to 4 months
- Calder removal - 1 to 2 months
- CPC1 well P&A - 5 to 6 months
- CPC1 heavy lift operations - 2 to 3 months

This schedule takes no account of planned delays before well P&A and / or removal. There are a few key points to note in the schedule:

- AP1 platform beds will be utilised up to final disembarkation from CPC1
- AP1 platform beds may be used for well crew during P&A with only the marine crew on the jack-up
- AP1 platform beds and NUI crew will be used to support DFPVI, and pipeline disconnect on the NUIs flying from CPC1, these activities will not be schedule critical
- For NUI well P&A the beds on the jack-up will be used with crew change flights direct to the jack-up (there is no reason to fly via CPC1), see Figure 5.3
- There will be a significant schedule gap between disembarkation and HLV operations

Figure 5.3 - Well P&A Jack-up Alongside a NUI

5.2 Previous Decommissioning Schedules

5.2.1 DP3 / DP4

Well P&A for DP3 and DP4 required a specific well intervention rig to be constructed and installed; this was because of the slant wells, drilled at a 60-degree angle from the platform. For this reason, well P&A on DP 3 and DP 4 took longer than for standard wells. It is anticipated that there are similar wells on the other NUIs in the field and on CPC1. This is reflected in indicative schedules shown in Figure 5.1 and Figure 5.2. It is understood that this rig is still available to Spirit. From available information it would seem that well P&A took about 5 months for each asset. To support staffing on board DP4 during P&A operations, Sprit Energy used the Borr Ran jack up positioned alongside the platform for accommodation.

Figure 5.2 above can only be indicative, but it can be seen that an extension of well P&A at a NUI will extend the duration to achieve disembarkation but will not impact the overall schedule.

5.2.2 Other Asset Decommissioning Schedules

As can be seen in Table 4-1 to Table 4-3 and the schedules in Figure 5.1 and Figure 5.2 following disembarkation there are only a few residual SECEs to maintained, which can be monitored remotely. It is standard practice that following disembarkation the helidecks are longer maintained as compliant to CAP437 [5]. Table 5-3 presents achieved schedules from COP to disembarkation for a number of UK assets. Platform # 2 in this table is a clear outlier; this was a major export hub with oil storage cells at the base of the structure, this needed a subsea export pipeline bypass and flushing of all oil pipelines from other platforms and subsea tiebacks.

The table shows that for large assets with a large number of platform and subsea wells, COP to disembarkation can be achieved in 12 months. It is worth noting that oil platforms are significantly more difficult to clean than gas platforms. There is a financial incentive to achieve this as soon as possible as this has a large impact on post COP operational costs.

Table 5-3: Durations from Cease of Production to Disembarkation for Recent UK Decommissioning Projects

#	PLATFORM TYPE	LOCATION	PRODUCTION	WELLS	FEATURES	DURATION
1	Large single steel jacket	NNS	Oil / Gas	~40	Subsea tiebacks	12 months
2	Single gravity-based structure	NNS	Oil / Gas	~30	Subsea tiebacks Major export hub Oil storage	27 months
3	Single steel jacket	CNS	Gas / Condensate	~25	Subsea tiebacks	18 months
4	Single steel jacket	NNS	Oil / Gas / Condensate	~18	Subsea tiebacks	12 months

5.3 Decommissioning Schedule Risks

The decommissioning project as a matter of good practice will establish a project risk assessment and management process; and it will be a primary expectation that the project management team manage these risks ensuring effective and timely delivery of the overall project. Regarding any impact on deferred flights the following can be expected:

- Any delay to the schedule up until disembarkation will directly extend OPEX and project management costs
- Well P&A crews for CPC1 will be located in accommodation on AP1 or the jack-up, a deferred crew change flight will not impact the schedule as the crew offshore will carry on with work until they are replaced
- Crew change for the CPC1 heavy lift vessels will be undertaken when the HLV is in its stand-off position to the north unimpeded by the windfarm
- Well P&A crew for Calder will likely be located on the jack-up, a deferred crew change flight will not impact the schedule as the crew offshore will carry on with work until they are replaced
- DP6 / DP8 / DPPA well P&A will not be impacted by the windfarm as crew change flights can be direct to the jack-up
- DP6 / DP8 / DPPA removal will not be impacted by the windfarm as crew change flights can be direct to the HLV

Delivery of any offshore project is subject to a number of variables that can impact on the programme; including, weather, specialist vendor availability, bed availability, equipment delays, regulatory approvals etc. These are all aspects and risks that a project management team need to address, the possibility of deferred flights due to the presence of the windfarm is another minor factor to be managed.

5.4 Decommissioning and Windfarm installation Schedule Overlap

Figure 5.4 and Figure 5.5 show indicative schedules for windfarm construction and Calder decommissioning respectively.

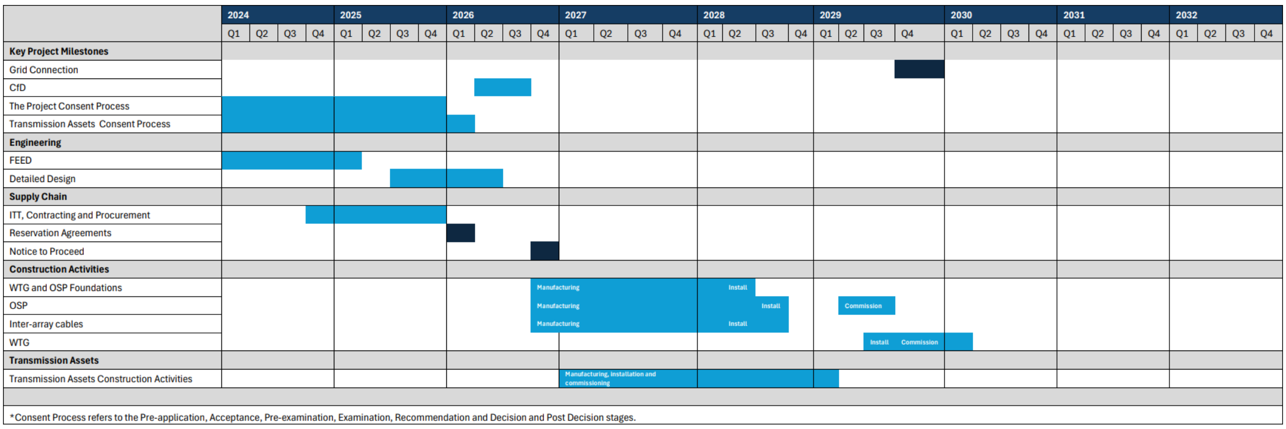


Figure 5.4 - Realistic Expected Installation Schedule for Generation Assets [12]

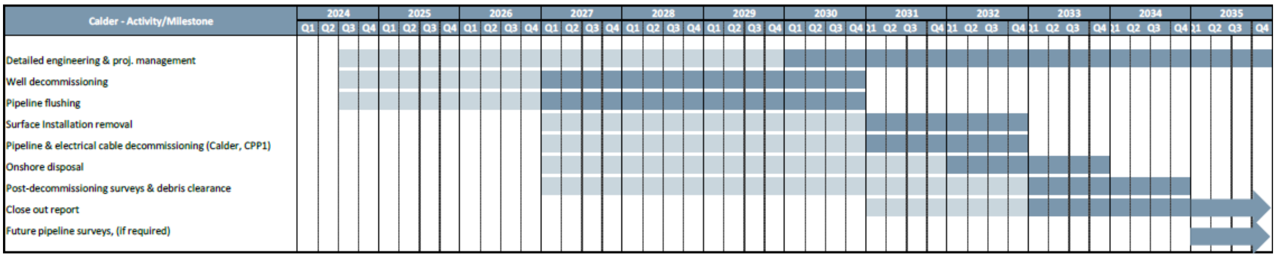


Figure 5.5 - Calder Decommissioning Timeframe [1]

No Decommissioning Programme has been published for CPC1, DP6, DP8 or DPPA; however, based upon the Calder Decommissioning Programme [1] decommissioning could be coincident with windfarm construction. Any safety risks associated with this can be managed as addressed in Section 6.6.

6 IMPACT OF WINDFARM ON MORECAMBE DECOMMISSIONING PROGRAMMES

6.1 Overview

This section considers the likely impact of the presence of the windfarm on decommissioning activities. This section has been prepared based upon Xodus' extensive experience of decommissioning programmes on the UKCS; and presents the Xodus view on the most likely sequence of events and decommissioning project delivery for facilities of this nature. It is recognised that at this time detailed decommissioning project programmes have not been developed for a number of these assets.

6.2 Central Processing Complex (CPC1)

6.2.1 Post COP

There will be no significant decrease in SECE maintenance requirements post COP until CPP1 is hydrocarbon free and / or all of the wells have been plugged and abandoned; however, there may be a small reduction associated with process equipment, i.e., once a processing vessel is isolated and air-gapped from any pressure source, statutory pressure vessel inspections are no longer required. It is reasonably foreseeable that there will be a reduction in maintenance associated with production systems.

The accommodation will remain in use throughout this phase, and it is likely that the majority of beds will be required, with transition of beds from operational to decommissioning project team and well P&A crew. A similar number of flights to CPC1 will be required per the operational phase subject to the same limitations arising from the presence of the windfarm as experienced during the operational phase. As this is a continuation of flights similar to the operational phase the conclusions of the Anatec [7] and DNV [9] reports apply.

The remaining operational crew and offshore decommissioning project team members will be located in the accommodation on AP1 and will be able to deliver the project activities with no impact from deferred flights. A delay to crew change as a result of a delayed or cancelled flight will not lead to a direct corresponding delay to the decommissioning project schedule. Specialist vendors will need to be mobilised; and as set out in the DNV report [9] this may lead to some limited additional vendor costs; no quantification of this is possible at this stage as the detailed programme has not been developed.

As for any offshore project, implementation is impacted by many factors and delays, managing these is a primary function of Project Management and the presence of the windfarm will not create any significant issues that are not typical for offshore project implementation. Therefore, any potential impacts, such as additional vendor costs, during this phase of the decommissioning can be mitigated through proper planning and management of the decommissioning campaign.

6.2.2 Well P&A

Well P&A will be undertaken using a jack-up rig positioned alongside DP1. The jack-up will have unimpeded access from the North of DP1 and has the designated 1.5nm marine buffer to the south in which to operate.

It is Xodus' experience that typically the well intervention crew will use the platform accommodation, where available with flights direct to CPC1 with impacts as per the operational phase [9]. Bed availability and schedule management is always a key area for offshore project management and other than specialist vendors as above, it is not foreseeable that flight delays will have a material impact on project schedule. Alternative flights can be made to the jack-up rig helideck but as this is alongside DP1 the situation is the same as flights to CPC1.

It is very unlikely that the jack-up vessel will require mooring, if this is the case, this is a specialist area, and it is common practice to develop mooring spreads where there is substantial sub-sea infrastructure around an operating platform. This will frequently include, oil and gas export pipelines, import pipelines from other facilities, subsea tieback pipelines and umbilicals, subsea structures and hydraulic umbilicals for Subsea Isolation Valves (SSIV), power and data cables. The presence of the wind turbines and interconnecting cables does not present an unusual obstacle to the development of a viable mooring spread design.

During an emergency the jack-up vessel can stand-off to the North of CPC1 and evacuation of the jack-up would be undertaken per the arrangements for CPC1 evacuation discussed in the DNV report [9]; which concluded that: there will be no impact on emergency evacuation and escape from CPC1.

All equipment required will be delivered to the jack-up via supply vessel, vessel movements from shore to the jack-up rig will not be impacted by the windfarm as these will as a matter of course be required to enter the platform statutory 500m exclusion zone and the 1.5nm marine buffer is sufficient for these supply vessel activities.

As above, a delay to a well intervention crew flight will not directly correspond to an overall project delay as the crew on the platform can continue work, with only an overtime impact. This is within the scope project management; and can be mitigated through proper planning and management of the decommissioning work schedule.

6.2.3 Post Disembarkation and Lighthouse Mode

There will be a schedule window between final disembarkation of all platform crew and the arrival of the Heavy Lift Vessel, this is a standard approach to de-risk any impact of decommissioning schedule on HLV costs. During Lighthouse Mode flights are no longer possible as the helideck is no longer maintained as compliant with CAP437 [5]. Inspection can be carried out via drone and intervention would only be necessary if an anomaly was identified; a result there is no impact from the windfarm. The project phase above will have delivered an asset that is stable and safe for approach by the HLV and crew, the asset condition having been agreed in advance with the HLV contractor.

6.2.4 Topsides and Jacket Removal

Removal of the CPC1 topsides and jackets will likely require a Super Heavy Lift Vessel, in particular due to the size and weight of CPP1 and AP1 topsides and /or the required hook height. The HLV contractor will determine the preferred and most efficient sequence of lifts. The HLV will have unrestricted access to the CPC1 complex from the north, and although not essential, it is the preference of HLVs to be positioned in the blow-off location with respect to the prevailing wind, meteorological data shows that the prevailing wind direction is from the south-west.

During this phase the CPC1 helidecks will be out of commission and all flights will be to the HLV. Due to the length of time the HLV will be in field it is likely that crew change flights will be necessary. These flights will be undertaken when the HLV is in the stand-off position to the North and will not be impacted by the presence of the windfarm. As a result, it is not foreseeable that the presence of the windfarm will directly cause any delays to the topsides and jacket removal schedule.

The HLV will not undertake crew change flights whilst is undertaking lifting operations, so there is no need to fly to the HLV whilst it is adjacent to CPC1.

6.2.5 CPC1 Summary

The following are the key points applicable to the decommissioning of CPC1:

- Post COP phase helicopter flights will continue to CPC1 largely per the operational phase until well P&A is complete
- Once the NUIs reach cease of Production there will be a decrease in the number of flights to CPC-1 that go on to one of NUIs, see Section 6.4
- There will be no significant decrease in SECE maintenance requirements post COP until CPP1 is hydrocarbon free and / or all of the wells have been plugged and abandoned; however, there may be a small reduction associated with process equipment
- Once the asset is hydrocarbon free and well P&A is complete there will be the opportunity for a significant reduction in SECE maintenance
- Any impact from the windfarm during this phase will be as detailed in the DNV report [9]
- There will be a shift in focus of operational people from production to cleaning, flushing, and purging of process systems and de-energisation of other systems
- It is Xodus' experience that platform beds will remain close to full utilisation until well P&A is complete
- The jack-up will have unimpeded access from the North of DP1 and has the designated 1.5nm marine buffer to the south in which to operate
- Well intervention specialist are likely to be accommodated on AP1 and any delay to vendor access will incur costs to Spirit Energy; but proper planning and management of these works can mitigate this impact
- The HLV will have unrestricted access to the CPC1 complex from the north, and although not essential, it is the preference of HLVs to be positioned in the blow off location with respect to the prevailing wind to the north of the complex
- HLV crew changes will be undertaken when the HLV is in the stand-off position to the North and will not be impacted by the presence of the windfarm
- It is not foreseeable that the presence of the windfarm will cause any significant delays to well P&A and the topsides and jacket removal schedule

6.3 Calder

6.3.1 Post COP

Following Cease of Production there will be a progressive reduction in requirements for maintenance personnel to fly to a NUI as SECEs are retired and as there is no longer a requirement for production resets and production critical maintenance; this will enable a focus on the remaining SECEs. DFPVI activities and physical disconnects on Calder will not be schedule critical so there will be no overall schedule impact from deferred flights.

6.3.2 Well P&A

Well P&A will be undertaken using a jack-up rig positioned alongside Calder and the jack-up has unrestricted access from the west of Calder and has the designated 1nm marine buffer to the east in which to operate. Jack-up rig beds can be used for the well intervention crew as there is no reason to fly these people via CPC-1. Although these flights will face the same restrictions as flights to Calder, an inability to undertake a crew change will not impact the schedule as the on-board crew will continue with activities until replaced.

6.3.3 Post Disembarkation and Lighthouse Mode

During Lighthouse Mode flights are no longer possible as the helideck is no longer maintained as compliant with CAP437 [5]. Inspection can be carried out via drone and intervention would only be necessary if an anomaly was identified; a result there is no impact from the windfarm.

6.3.4 Topsides and Jacket Removal

Calder removal is not likely to require one of the Super Heavy Lift Vessels; however, this is dependent upon the availability of lift vessels. The lift vessel is likely to be in field for less than 1 week and crew changes will not be necessary. The HLV will have unrestricted access to Calder from the west, a position where the prevailing wind will not blow the HLV on to the platform.

The HLV will not undertake crew change flights whilst is undertaking lifting operations, so there is no need to fly to the HLV whilst it is adjacent to Calder.

6.3.5 Calder Summary

The following are the key points applicable to the decommissioning of Calder:

- Post Cease of Production there will be a progressive reduction in requirements for maintenance personnel to fly to a NUI as SECEs are retired and as there is no longer a requirement for production resets and production critical maintenance
- It will remain necessary to maintain the remaining SECEs with flights from CPC1, but this will be at a reduced frequency
- Flights to undertake production resets following a trip will not be required
- Well intervention specialist are likely to be accommodated on the jack up rig
- The jack-up has unrestricted access from the west of Calder and has the designated 1.5nm marine buffer to the east in which to operate
- The HLV will have unrestricted access to the Calder platform from the west, this is still in a position where the prevailing wind is not blowing the lift vessel on to the platform
- As the HLV will be in field for a very short period crew change flights will not be required and there will be no impact from the windfarm

- It is not foreseeable that the presence of the windfarm will cause any significant delays to well P&A and the topsides and jacket removal schedule

6.4 NUIs (DP6 / DP8 / DPPA)

6.4.1 Post COP

There will still be active and required SECEs on the NUIs, but there will be a progressive reduction following Cease of Production through to Lighthouse Mode. Access to the platform for production upsets will no longer be required. Flights to the NUIs from CPC1 will still be required to maintain the remaining SECEs but there will be a reduced demand.

6.4.2 Well P&A

Well P&A will be undertaken using a jack-up rig positioned alongside the platform, crew change flights can be undertaken direct to the jack-up and as these are all well to the North of CPC1 the windfarm will have no impact on this phase.

6.4.3 Post Disembarkation

During Lighthouse Mode flights are no longer possible as the helideck is no longer maintained as compliant with CAP437 [5]. Inspection can be carried out via drone and intervention would only be necessary if an anomaly was identified; a result there is no impact from the windfarm.

6.4.4 Topsides and Jacket Removal

As these assets are to the North of CPC-1 and remote from the windfarm, there will be no impact on the removal phase.

6.4.5 NUIs (DP6 / DP8 / DPPA) Summary

The following are the key points applicable to the decommissioning of the NUIs:

- Post Cease of Production there will be a progressive reduction in requirements for maintenance personnel to fly to a NUI as SECEs are retired and as there is no longer a requirement for production resets and production critical maintenance
- It will remain necessary to maintain the remaining SECEs with flights from CPC1, but this will be at a reduced frequency
- Flights to undertake production resets following a trip will not be required
- Well intervention specialist are likely to be accommodated on the jack up rig with unimpacted direct flights from shore possible
- The jack-up has unrestricted access to the NUIs which is not impacted by the windfarm
- The HLV has unrestricted access to the NUIs which is not impacted by the windfarm
- It is not foreseeable that the presence of the windfarm will cause any delays to the topsides and jacket removal schedule given the distance between these assets and the windfarm site

6.5 Pipelines

The only pipelines within the windfarm location are PL195 and PL 205 between DP3 and CPP1, which have already been decommissioned and left in situ; and PL1965 from Calder to the Rivers Gas terminal.

It is likely that PL1965 will be left in situ as was the case for the pipelines between DP3 and DP4 and CPP1, although this will be subject to a full environmental impact assessment and derogation. If the pipelines are left in-situ as for the DP3 and DP4 Decommissioning Programme [2], the 500m buffer provided either side of the pipelines provides sufficient space for the following:

- Future monitoring of the pipelines within the windfarm
- ROV survey to determine depth of burial
- Spot rock dumping where a pipeline has become exposed

Decommissioning of the other in pipelines in Morecambe Bay is not impacted by the presence of the windfarm.

6.6 Decommissioning Safety

Although helicopter flights are still required to CPC1 and on to the NUIs until the assets are fully disembarked; deferment of flights to the assets during this phase will not lead to a significant risk to Spirit Energy personnel, the jack-up rig crew, or the HLV crew; consistent with the assessment set out in detail in the DNV report [9].

There will be a progressive removal of SECEs as the Major Accident Hazards (MAH) reduce throughout the decommissioning programme; flights will be required to maintain the remaining SECEs until final disembarkation; however, this is simply an extension of the operational phase which is covered in the DNV report [9].

Throughout the decommissioning phase there will be a continuing decrease in risk to personnel as measured by Individual Risk Per Annum (IRPA) as MAH are reduced and removed and the requirement to fly to NUIs for SECE maintenance and production critical maintenance is reduced. Consistent with the assessment in the DNV report [9], there is no basis to assert that the presence of the windfarm represents an increase in risk to personnel involved in the decommissioning programme.

It is possible that decommissioning of Calder and /or CPC1 will coincide with windfarm installation. If this is the case there is a well-developed industry methodology to manage Simultaneous Operations (SIMOPS), the application of which will ensure the management of risks to personnel in both projects to As Low As Reasonably Practicable (ALARP).

The conclusions of the DNV report [9] that there will be no impact on emergency evacuation and escape from either CPC1 or any of the NUIs are applicable to people located on a platform during the decommissioning phase. In the event of an emergency when there is a jack-up rig or Heavy Lift Vessel in the field there is sea room to the North of CPC1 and the West of Calder to allow the vessel master to stand-off.

7 DECOMMISSIONING COSTS

7.1 Overview

Xodus have undertaken a Level 5 estimate of the decommissioning costs for the Morecambe Bay; typically, a Level 5 estimate is undertaken to provide Order of Magnitude costs in an early planning phase. As detailed information has not been provided by Spirit Energy or Harbour, this is based upon the best available public information and estimating norms used by Xodus and available via the NSTA decommissioning cost portal [10]. The costs are aligned with the industry and OEUK required work breakdown structure [11].

7.2 Estimating Norms

The cost estimate has been undertaken utilising the norms shown in Table 7-1 and Table 7-2.

Table 7-1: Decommissioning Estimating Norms

SOURCE	ITEM/NORM	VALUE	UNIT
OEUK	Topsides Prep	716	£/te
OEUK	Topsides Removal	2,374	£/te
OEUK	Jacket Removal	2,910	£/te
Xodus	Onshore Dismantling/Recycling Norm - Topsides	225	£/te
Xodus	Onshore Dismantling/Recycling Norm - Jacket	250	£/te
OEUK	Cost/Well - Platform	3.47	£M/well
OEUK	Cost/Well - Subsea	8.57	£M/well
Xodus	Operator PM	6%	% overall cost
Xodus	Post COP OPEX	1,500	£/te

Table 7-2: Vessel Day Rates

VESSEL	RATES (£/DAY)	COST BASIS
Small CSV	130,000	Xodus Norm
Large CSV	200,000	Xodus Norm
Survey Vessel	20,000	Xodus Norm
HLV	800,000	Xodus Norm
Jack-up Rig	750,000	Xodus Norm

VESSEL	RATES (£/DAY)	COST BASIS
Rockdump Vessel	180,000	Xodus Norm

7.3 Metrics

The following metrics have been assumed for the Morecambe Bay assets for developing the cost estimates as shown in Table 7-3.

Table 7-3: Decommissioning Estimate Metrics

PLATFORM	TOPSIDES WEIGHT (Te)	JACKET WEIGHT (Te)	NO. OF PLATFORM WELLS
Calder	625	1283.7	4
South Morecambe NUIs (DP5, DP6, DP8)	6,763	2739	6
Morecambe Complex (AP1, CPP1 & DP1)*	40,578	17,422	8

* An assumption has been made that the total 58,000 te platform weight for the Morecambe Complex is split on 30%/70% for jacket/topsides respectively.

7.4 Cost Summary

Based on the norms and metrics above the following Level 5 estimate has been produced, Table 7-4 to Table 7-6.

Table 7-4: Calder Decommissioning Estimate

CALDER PLATFORM			
WBS	DESCRIPTION	COST (£M)	COST BASIS
1	Operator PM	1.5	6% of project cost
2	Post CoP OPEX	0.9	SNS post COP norm
3	Well Decommissioning	13.9	OEUK Benchmark cost/well; 4 wells assumed
4	Facilities& Pipeline Permanent Isolation and Cleaning	0.9	SNS post COP norm
5	Topsides Prep	0.4	OEUK Benchmark cost /te for SNS & IS
6	Topsides Removal	1.5	OEUK Benchmark cost /te for UKCS
7	Jacket Removal	3.7	OEUK Benchmark cost /te for UKCS
8	Onshore Recycling	0.5	Xodus Norm
9	Subsea Infrastructure	2.0	Xodus Norm, allowance for pipeline disconnections
10	Site Remediation	0.3	Xodus Norm, allowance for one post decom survey
11	Post Decom Monitoring	1.0	Xodus Norm, allowance for 3 further surveys
	Total	26.6	

Table 7-5: CPC1 Decommissioning Estimate

MORECAMBE CENTRAL PROCESSING COMPLEX (AP1, CPP1 & DP1)			
WBS	**DESCRIPTION**	**COST (£M)**	**COST BASIS**
1	Operator PM	17.0	6% of project cost
2	Post CoP OPEX	60.9	SNS post COP norm
3	Well Decommissioning	27.8	OEUK Benchmark cost/well; Assumed 8 wells
4	Facilities& Pipeline Permanent Isolation and Cleaning	2.8	SNS post COP norm
5	Topsides Prep	29.1	OEUK Benchmark cost /te for SNS & IS
6	Topsides Removal	96.3	OEUK Benchmark cost /te for UKCS
7	Jacket Removal	50.7	OEUK Benchmark cost /te for UKCS
8	Onshore Recycling	13.5	Xodus Norm
9	Subsea Infrastructure	1.3	Xodus Norm, allowance for disconnection of Export line (leave *in* situ)
10	Site Remediation	0.1	Xodus Norm, allowance for one post decom survey
11	Post Decom Monitoring	0.3	Xodus Norm, allowance for 3 further surveys
	Total	299.6	

Table 7-6: NUIs Decommissioning Estimate (cost per NUI)

MORECAMBE PLATFORM (NUIs)			
WBS	**DESCRIPTION**	**COST (£M)**	**COST BASIS**
1	Operator PM	3.8	6% of project cost
2	Post CoP OPEX	10.1	SNS post CoP norm
3	Well Decommissioning	20.8	OEUK Benchmark cost/well; 6 wells assumed
4	Facilities& Pipeline Permanent Isolation and Cleaning	0.9	SNS post CoP norm
5	Topsides Prep	4.8	OEUK Benchmark cost /te for SNS & IS
6	Topsides Removal	16.1	OEUK Benchmark cost /te for UKCS
7	Jacket Removal	8.0	OEUK Benchmark cost /te for UKCS
8	Onshore Recycling	2.2	Xodus Norm
9	Subsea Infrastructure	0.8	Xodus Norm, allowance for pipeline disconnections
10	Site Remediation	0.1	Xodus Norm, allowance for one post decom survey
11	Post Decom Monitoring	0.3	Xodus Norm, allowance for 3 further surveys
	Total	67.9	

On the above basis the total costs for decommissioning Morecambe Bay are estimated to be:

- Calder £26.6M
- Spirit Energy Assets £299.6 +(3x£67.9) = £503.3M

7.5 Windfarm Impact on Decommissioning Costs

The largest increase to costs to a decommissioning programme could arise from increased in-field durations for contracted vessels if the in-field duration is extended. It should be recognised that actual contracted costs are subject to availability at the time of contracting; however, current estimated day rate costs are provided in Table 7-2. The key points relating to the potential of increased in-field durations and hence cost are:

- Sensible project scheduling will ensure that there is a gap between planned disembarkation and HLV arrival, as a result schedule growth through the on platform phases will not extend HLV in-field costs
- For CPC1 removal the HLV can operate to the north with crew changes undertaken in the stand-off position.
- For Calder removal the HLV will not be in field long enough to require a crew change flight
- For CPC1 the well P&A crew can be located in the accommodation on AP1, any deferred crew change flights will not delay activities as the on board crew will carry on with work until replaced
- For Calder the well P&A crew can be located in the accommodation on jack-up rig, any deferred crew change flights will not delay activities as the on board crew will carry on with work until replaced
- Delays in the cleaning, flushing activities on NUIs will have no overall impact as these will not be schedule critical
- For DP6, DP8 and DPPA the windfarm will have no impact on well P&A and HLV activities.

The following have the potential for cost growth:

- Any financial impact of deferred flights during the operational phase will continue during the post COP phase, obviously with the exception of lost production costs
- For CPC-1 delays to the preparation to get to point of disembarkation will incur additional facility running costs, predominantly for offshore crew and power generation
- Delays in flying specialist vendors for decommissioning activities will incur additional personnel costs with the vendor

Achieving the disembarkation date whilst managing delays from a wide variety of sources will be a key focus for the decommissioning project management team, deferred flights due to the windfarm are a minor additional factor to be managed.

Given the above, the likely impact on project costs specifically related to the presence of the windfarm are not remotely close to the amounts claimed by Spirit Energy for South Morecambe, tens of millions of pounds; and by Harbour, £3-10 million for Calder. These are gross over-estimates.

8 RESPONSE TO THE RELEVANT REPRESENTATIONS

In the Spirit Energy Relevant Representation, they state:

1. *7.1.1 "As the wider Morecambe field has yet to be decommissioned, the Project has potential implications on access for jack up rigs and large heavy lift vessels which require a 1nm (1.8km) wide corridor. The proximity of the windfarm will also impact the ability to safely manoeuvre vessels in the area as heavy lift vessels and rigs require approximately a 1.5nm (2.8km) radius for manoeuvring. Jack up rigs relying on anchor spreads will not have the available seabed area due to the presence of cables."*

The protective provisions provide for a 1.5nm marine buffer around CPC-1 and 1nm at Calder.

The jack-up rig and heavy lift vessel have access to a large arc to the north of CPC1 and to the west of Calder with no obstructions and sufficient manoeuvring space. Although not essential, it is the preference of HLVs to be positioned in the blow off location with respect to the prevailing wind, in this case to the North of the complex. To the west of Calder is a location in which the prevailing wind will not be blowing the HLV onto the platform.

It is very common for a moored vessel to be located close to a platform. The seabed around large oil and gas complexes will frequently include, oil and gas export pipelines, import pipelines from other facilities, subsea tieback pipelines and umbilicals, structures and hydraulic umbilicals for Subsea Isolation Valves (SSIV), and power and data cables. The presence of the wind turbines and interconnecting cables does not present an unusual obstacle to the development of a viable mooring spread design.

2. *7.1.2 "As identified at Part 5: Aviation Related Safety, the proximity of the wind turbines to the Affected Assets will likely restrict the ability to fly to the asset on a continual basis to carry out decommissioning activities in all phases of the Project (this has an approximate financial impact noted below as still accurate). This will also result in an extension to the overall decommissioning schedule and associated knock-on impacts on operations (delays, cancelled flying) presenting an overall increase in risk to the decommissioning activities."*

Access to platforms will still be required during the decommissioning phase after COP.

The potential financial impact presented by Spirit Energy and Harbour are exaggerated, as detailed in Section 7, as follows:

- There will be a schedule break between on completion of on platform activities and final removal, so lift vessel costs are not at risks from extensions to the on platform schedule
- Well P&A crews will be based in accommodation on AP1, or on the jack-up rig, if a flight is deferred, there are still crew members on board to continue work
- Any crew changes on the HLV can be undertaken to the HLV with no impact from the windfarm
- The decommissioning project team workforce will be located on CPC1, in the event of a deferred flight there will still be work party members on board to carry on work
- Decommissioning project work on the NUI could be delayed if it is not possible to fly to the NUI on a planned day; however, NUI on platform work will not be schedule critical

- A deferred flight could lead to increased overtime costs and vendor specialist costs, but such delays are always possible; and the windfarm is just another factor, amongst many, for the project management team to address

There is no basis to conclude that the presence of the windfarm increases risk to personnel during decommissioning.

3. *7.1.3 "The area proposed for the windfarm is also in the area of the decommissioned DP3 asset and pipelines. The majority of the infrastructure at DP3 was removed, however buried pipelines remain in-situ. Spirit is required to close out the decommissioning programmes by demonstrating clear seabed for pipeline corridors and the 500mz of where DP3 was previously located. Spirit would therefore still require access to the decommissioned pipeline (500m either side) in order to demonstrate that all potential residual hazards and debris do not remain. This access could be limited by the presence of the windfarm preventing Spirit from closing out its decommissioning programmes."*

A 500 metre zone either side of the decommissioned DP3 pipeline has been provided.

4. *7.1.4 Furthermore, post-decommissioning surveys are required in these areas for a number of years until the regulator is satisfied, and the work within the windfarm (laying cables, surveys, etc) will need to demonstrate that it will not have an impact on Spirit's decommissioning obligations (for example, by operations negatively impacting Spirit's pipelines that remain in-situ).*

A 500 metre zone either side of the pipelines and cables within the windfarm has been provided.

5. *7.1.5 It is anticipated that aviation restrictions could result in significant changes to the length of decommissioning campaigns. Such delays to complex decommissioning activity would inevitably have very significant cost implications (not currently addressed in protective provisions), well into the tens of millions of pounds. Added to other mitigation and compensation for which the Applicant will be responsible, Spirit is concerned about the ability of the Applicant to maintain a viable project whilst addressing these foreseeable impacts.*

Spirit Energy state that the cost impact from the presence of the windfarm would be well into tens of millions of pounds; and Harbour state £3-10 million for Calder decommissioning. These are grossly over-estimated. There is no basis to reason that the presence of the windfarm will have a significant impact on the duration of decommissioning campaigns and the costs as detailed in Section 7.5.

6. *6.5 The ability to safely manoeuvre jack up rigs onto, and off, locations within, and close to, the Project must not be compromised. A minimum obstruction free radius of 1.5nm surrounding each platform has been requested to deploy spread moored vessels, including heavy lift vessels and drilling rigs into position. The use of dynamic positioning and anchors must also be considered for larger vessels interacting with the platform. Dynamic positioning is achieved by a number of thrusters operating continuously to compensate for any movement of the vessel. In the event that the vessel loses power, one or more thrusters fail, or if the sea state or weather conditions are sufficiently strong to overcome the vessel power, the vessel may drift. Where anchors are used, the vessel will often not have its own propulsion and will rely on tugs when relocating. Due to shallow depths and strong tidal currents up-to 2.5 knots in EIS, the use of Dynamic Positioning system on a heavy lift decommissioning vessels can be significantly restricted requiring spread anchor mooring system.*

A marine buffer of 1.5nm has been provided around CPC1 and 1nm around Calder. Decommissioning activities at Calder will be significantly shorter than for CPC1 and unrestricted access is available from the west of Calder. There is no reason to believe that mooring is required; the Allseas Pioneering Spirit, undertook removal of Spirit's DP3 and DP4 utilising dynamic positioning. Regardless, as above development of a mooring spread design around complex oil and gas assets is commonly undertaken and this would not present an unusual challenge.

7. *5.7.5 Furthermore, during the field decommissioning operations, the helicopter operations will be conducted to the helidecks onboard the decommissioning vessels/barges/rigs which can be positioned on the south face of the existing offshore installations which would necessitate further reducing the distance between the vessel/barge/rig helideck and the potential location of turbines – further degrading safe flying operations.*

Flights to vessels adjacent to the CPC1 and Calder face the same restrictions as flights to the platform helidecks, there may be some restrictions, but these can still be conducted safely as set out in the DNV report [9]. Flights to decommissioning vessels located at the NUIs to the north are not impacted by the windfarm. Lift vessels and jack-up rigs can approach from the North of CPC1 and the west of Calder with no reduction in the aviation buffer provided.

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